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Update of the Electricity Market Impacts Associated with the Proposed Northern Pass Transmission Project

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Prepared for

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London Economics International LLC ("LEI") was retained by Northern Pass Transmission, LLC ("NPT") to develop an economic impact analysis of the proposed Northern Pass Transmission Project. LEI has made the qualifications noted below with respect to the information contained in this report and the circumstances under which the analysis was prepared.

While LEI has taken all reasonable care to ensure that its analysis is complete, wholesale electricity markets are highly dynamic, and thus certain recent developments may or may not be included in LEI's analysis. Interested parties should note that:

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1 Executive Summary

On October 28, 2016, Northern Pass Transmission LLC and Public Service Company of New Hampshire d/b/a Eversource Energy (collectively "Applicant"), developers of the Northern Pass Transmission Project ("NPT", "Northern Pass", or "Project"), were authorized by the New Hampshire Site Evaluation Committee ("SEC"), pursuant to its Order on Applicants' Motion for Rehearing ("Order"), to undertake a comprehensive recalculation of the market analysis submitted as part of their Application in October 2015. This *Update of the Electricity Market Impacts Associated with the Proposed Northern Pass Transmission Project* ("Updated Analysis") incorporates the most recent FERC-approved demand curves ("Marginal Reliability Impact" or "MRI" curves) in ISO-NE's Forward Capacity Market ("FCM") and more recent natural gas price trends (based on Energy Information Administration's ("EIA") Annual Energy Outlook ("AEO") 2016[1]) into an updated analysis of the wholesale electricity market benefits from Northern Pass. In addition, other aspects of the wholesale electricity markets have evolved since mid-2015, when LEI prepared its *Cost-Benefit and Local Impact Analysis of the Proposed Northern Pass Transmission Project*. LEI's update takes into account new inputs that drive energy and market prices, such as, demand levels using the most updated ISO-NE load forecast, the costs for the generation technologies expected to enter the market, and various CO_2 related price parameters (see Section 2 for full discussion of market updates).

The overall methodology and modeling approach taken to calculate the benefits in the Updated Analysis is unchanged from LEI's previous analysis in October 2015. Specifically, the market benefits of Northern Pass are measured as a function of *the difference in market prices* between the Base Case and the Project Case:

- The Base Case outlook continues to assume normal system operations and average load conditions, based on ISO-NE's "50/50" load forecasts (as noted above, we used the latest ISO-NE load forecast) and also builds on conservative market-oriented expectations for marginal costs of generation, including fuel prices, variable O&M costs, and carbon allowance prices. LEI further assumed that the New England wholesale electricity market converges and maintains a balanced supply-demand profile over the longer term. In summary, the Base Case continues to represent a future evolution from the current status quo, based on economically rational investor response to the projected market dynamics and system needs.

- The Project Case includes the addition of NPT (the project characteristics of Northern Pass have not changed apart from the date of commercial operation). Consistent with the previous analysis presented in LEI's Report from October 2015, the Project Case is re-calibrated to consider how other generators and investors will respond to the market

[1] The complete Annual Energy Outlook 2016 was released on September 15, 2016.

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price impacts created by NPT. [redacted]

In addition, for modeling purposes Northern Pass's capacity supply obligation ("CSO") is assumed to begin with FCA #12 (previously FCA #11). The benefits analyzed therefore consider an 11-year period from 2020-2030 as opposed to 2019-2029 in LEI's October 2015 Report). Other characteristics of the Project (such as energy flows of 7,958 GWh and a CSO of 1,000 MW) remained unchanged from LEI's October 2015 Report.

LEI concluded after incorporating all of the market updates (referred to hereafter as "Updated Analysis") that Northern Pass still delivers substantial wholesale market and environmental benefits over an 11-year average (2020-2030).[2] Over the modeling horizon, wholesale electricity market benefits average $614 million per year for New England compared to $851 million to $866 million in LEI's October 2015 Report. Over the 11-year modeling horizon, this represents a net present value ("NPV") of approximately $4.6 billion using a 7% discount rate.[3] This translates to approximately $63 million on average per year in wholesale electricity market benefits for New Hampshire compared to between $81 and $83 million on average per year reported in LEI's October 2015 Report (New Hampshire benefits reflect the higher share of peak demand and total demand in CELT 2016). Over 11 years, this is approximately $468 million on an NPV basis for New Hampshire, using a 7% discount rate. Section 3 presents in more detail the wholesale energy and capacity market benefits of the Project.

In summary, although the market rules have evolved and supply conditions have changed, NPT continues to create a statistically significant reduction in annual average energy price and also continues to lower capacity prices in the FCM. Figure 1 provides a summary of all the updated benefit metrics compared to LEI's October 2015 Report.

[2] LEI's updated analysis covers calendar years 2020-2030 as opposed to 2019-2029 in LEI's October 2015 Report. The in-service date of Northern Pass is 2019 but for modeling purposes the Updated Analysis reflects an in-service date of January 1, 2020.

[3] LEI is using a 7% discount rate for illustrative purposes, which is the same discount rate used in the LEI October 2015 Report.

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Figure 1. Annual Wholesale Electricity Market Benefits Summary ($ millions, nominal)

	New England		New Hampshire	
Benefit Categories	**Updated Analysis**	**October 2015 Report**	**Updated Analysis**	**October 2015 Report**
Wholesale Market	($millions, nominal)	($millions, nominal)	($millions, nominal)	($millions, nominal)
Wholesale Market Benefits (11-yr avg)	$614	$851 - $866	$62.8	$81.0 - $82.5
Energy Market (11-yr avg)	$88	$80 - $100	$8.6	$8.2 - $10.2
Capacity Market (10-yr avg)	$579	$843 - $848	$59.6	$79.6 - $80.1
Production Costs	($millions, nominal)	($millions, nominal)		
Production Cost Savings (11-yr avg)	$389	$330 - $425		
Environmental Benefits	(million metric tons)	(million metric tons)		
CO2 Reduction (11-yr avg)	3.2	3.3 - 3.4		

Wholesale energy market benefits for New England are projected to be approximately $88 million per year on average, compared to an annual average range of $80 million to $100 million in LEI's October 2015 Report. These benefits take into account EIA's AEO 2016 natural gas price trends, lower energy demand forecasts from ISO-NE's 2016 CELT, recent supply commitments to the market and retirements based on FCA #10 results and changes to the FCM market rules, as well as modifications to the generic new entry technology type given ISO-NE's most recent estimates for cost of new generation. See Section 2 for how these key updates affect the wholesale energy market benefits and Section 3 for a complete discussion of the energy market results.

Wholesale capacity market benefits incorporate the MRI demand curve (and the transition curves), as well as the latest proposal by ISO-NE to change the reference technology for the Net Cost of New Entry ("Net CONE") from a combined cycle gas turbine to a combustion gas turbine (frame-based peaker). The capacity market analysis also takes into account evolution of market conditions in neighboring markets, such as New York. LEI's updated analysis suggests that Northern Pass would result in benefits of approximately $579 million on average per year over 10 years (2021-2030). This is lower than average annual benefits of $843 million to $848 million estimated over the 2020-2029 timeframe in LEI's October 2015 Report - but still sizable. The key drivers for the lower estimates include reforms in the FCM (the implementation of the MRI), modifications in the ISO-NE's estimate of Net CONE, as well as updated new entry (from FCA # 10) and expected retirements. See Section 3.2 for a complete discussion of the capacity market results.

Production costs savings, as a result of Northern Pass, are expected to be approximately $389 million on average per year. In line with the energy and gas price trends, this falls between the expected production cost savings of the two gas scenarios presented in LEI's October 2015 Report, which were $330 million and $425 million on average per year. See Section 3.3 for a complete discussion of the production cost savings.

CO_2 emissions reductions as a result of Northern Pass are expected to be approximately 3.2 million metric tons on average per year, compared to 3.3-3.4 million metric tons on average per year in LEI's October 2015 analysis. The CO_2 reductions are a function of which resources are being displaced by Northern Pass (typically gas-fired resources). The benefit of CO_2 emissions reduction can also be presented in monetary terms by reference to the Social Cost of Carbon ("SCC"), which is also slightly lower in the Updated Analysis using the latest updates and simulations from the Interagency Working Group on Social Cost of Greenhouse Gases. We estimate that figure to be $25 to $189 million per annum under the Updated Analysis. See Section 3.4 for a discussion of the environmental benefits.

The local economic benefits were not updated in this analysis. Local economic benefits are a function of expected local spending during construction (which has not changed). Once the Project achieves commercial operations local economic benefits are a function of the wholesale electricity market cost savings for ratepayers, which as noted above are similar in magnitude to the estimates presented in LEI's Report from October 2015. Therefore, LEI did not re-estimate the local economic benefits in this Updated Analysis.[4]

LEI continues to believe that wholesale electricity market benefits projected under this Updated Analysis are conservative. As in the original analysis presented in LEI's October 2015 Report, we continued to use weather normal load forecast and "normal" natural gas market conditions. We also continued to assume investment response that is rational and timely (without delay). Scenarios could have also been studied whereby an abrupt retirement of large baseload resources in the Base Case (such as a nuclear plant) causes both energy and capacity prices to increase, or New England experiences another polar vortex situation in the 2020s, raising energy prices to levels seen in the winter of 2013/14. These scenarios would demonstrate that a project such as Northern Pass can provide valuable "insurance" to consumers, mitigating some of the negative consequences (e.g., potential cost increases) associated with such events.

[4] Calculating the local economic benefits must also be done sequentially only after finalizing the wholesale electricity market benefits. As such, there was insufficient time to conduct this analysis and incorporate it into the Updated Analysis.

2 New England market developments since mid-2015

Wholesale electricity markets are constantly evolving and are highly dynamic. Since LEI initiated the modeling of Northern Pass in mid-2015, a number of new market developments have emerged, which create both upside and downside effects on the forecast market-related benefits of Northern Pass. The sections below provide an overview of the changes that were incorporated into this Updated Analysis.

2.1 Energy Market Developments

The biggest driver affecting energy prices is the cost of the fuel at the margin of the supply curve (which is primarily natural gas in New England). The natural gas prices in the Updated Analysis are based on latest market fundamentals and EIA's long term views on price trajectory for natural gas in the US. The updated gas price outlook reflects a level in between the two natural gas scenarios used in LEI's October 2015 Report, and as such the overall energy market benefits also consistently fall in this range. LEI also incorporated the most current ISO-NE outlook for demand and cost of new generation. In general, the lower demand projections reduce the energy market benefits while the cost of generation and associated change of the new entry technology in the FCM to peakers (as opposed to combined cycle power plants) will increase energy market benefits. While LEI has made updates to other inputs such as imports, carbon allowance prices, and transfer limits, these do not result in significant changes to the energy market outcomes.

2.1.1 Fuel Prices

LEI's October 2015 Report included two natural gas price scenarios that were based on two different approaches for developing a gas price outlook (see Section 5 of the 2015 LEI Report for more details on how these were derived). Only one of these outlooks (known as "LCOP/HH") used the EIA's then current AEO as an input in the forecast. As such, LEI only ran an update of this gas price scenario in the Updated Analysis.

In the EIA's Reference Case in AEO 2016, average annual US natural gas prices at the Henry Hub remain at about $5.0/MMBtu in 2015 dollar terms from 2025 through 2040, therefore, rising in nominal terms only by about 2% per annum.[5] This price trajectory is largely the result of increased natural gas production brought about by technology improvements in the development of shale gas resources, which results in higher rates of recovery at lower costs.[6] This production growth holds down natural gas prices as compared to the EIA's AEO 2015 outlook. Delivered natural gas prices to New England must also include a transportation adder.

[5] EIA. Market Trends: Natural Gas. <http://www.eia.gov/outlooks/aeo/MT_naturalgas.cfm#price_product>. Accessed December 28, 2016.

[6] Ibid.

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When building on the EIA's AEO outlook for wellhead gas prices, LEI estimated the transportation adder using its Levelized Cost of Pipeline Model. See Section 5 for additional details about the gas price forecast.

[redacted] The delivered gas price levels in the Updated Analysis are closer to the price levels in the GPCM/MS gas scenario in LEI's October 2015 Report. Figure 2 below shows a comparison of the updated gas price outlook relative to the two gas price scenarios used in LEI's October 2015 Report. Notably, LEI's latest outlook for the longer term falls between the two gas price forecasts previously modeled, indicating that the range used in the LEI's October 2015 Report is still reasonable, and therefore, the results presented in the LEI's October 2015 Report surrounding wholesale energy market benefits also continue to be valid.

[redacted]

[redacted]

Other fuel prices were also updated – on the basis of AEO 2016 and market forwards. The distillate oil price is based on the heating oil forwards for 2017 and 2018, and escalated at the same rate as the AEO 2016 crude oil forecast in the long term.[8] The residual oil price forecast was developed based on a multi-year average of the ratio of residual and distillate oil prices. [redacted] shows the forecasted residual and distillate oil prices. However, because oil is always more expensive than natural gas under normal weather conditions, oil-fired generation typically run less than 2% of the time based on economic dispatch, and therefore does not materially affect annual average energy prices. In reality, these oil-fired resources may run more than expected in the dispatch simulations as a result of very cold days where the price of natural gas is very high (due to higher than normal residential demand for oil from heating applications). We have conservatively not considered such weather conditions in our modeling.

[redacted]

[8] *See* EIA Annual Energy Outlook 2016. Figure IF4-6. Brent crude oil and Henry Hub natural gas spot prices in the Reference Case. < http://www.eia.gov/outlooks/aeo/pdf/0383(2016).pdf>. Accessed December 28, 2016.

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2.1.2 Demand

LEI updated the demand forecast to incorporate ISO-NE's latest projections regarding load growth, energy efficiency projects and behind-the-meter solar PV, based on the CELT 2016, which was issued by ISO-NE in May 2016.[11] LEI also took into account ISO-NE's 2016 solar PV forecast that was released in April 2016, which also specifies the expected levels of solar build out in the region.[12] [redacted] and [redacted] show how the peak demand and total demand forecasts differ between CELT 2015 and 2016. [redacted] On average, total demand is approximately 0.9% lower than in CELT 2015, and peak demand is approximately 2.0% lower. All else being equal, lower energy consumption would result in lower energy market benefits from any project like NPT.

[9] EIA Annual Energy Outlook 2016. Figure MT-60. Average annual minemouth coal prices by region in the Reference case, 1990–2040 (2015 dollars per million Btu). <http://www.eia.gov/outlooks/aeo/pdf/0383(2016).pdf>. Accessed December 28, 2016.

[10] Coal units are not expected to affect annual average energy prices significantly due to the fact that the few operating units typically do not set price.

[11] For the hourly load profile, LEI used ISO-NE's hourly load forecast in 2016 for each sub-region. Based on this sub-regional hourly load shape, LEI forecasted the hourly load shape in future years by scaling the shape with the forecasted peak load and total energy demand in those years.

[12] ISO-NE. Final 2016 PV Forecast. Distributed Generation Forecast Working Group. April 15, 2016.

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[redacted]

2.1.3 Carbon allowance prices

[redacted] This results in approximately 6% lower RGGI prices ($0.35/short ton) on average than what was used in LEI's October 2015 Report over the 2020 to 2029 modeling timeframe. All else being equal, lower RGGI allowance prices would result in lower energy prices. However, as carbon costs only constitute a small share of the short-run marginal costs of generation, these results do not significantly impact the wholesale energy market benefits.

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2.1.4 Transfer limits

LEI used the transfer limits published in ISO-NE PAC 2016 materials, "Transmission transfer capabilities update, June 10, 2016." Since the publication of LEI's October 2015 Report, ISO-NE has not make any significant changes to the interface limits in the long term.[13] [redacted]

2.1.5 Imports

ISO-NE is well interconnected with surrounding regions, with ties to the New Brunswick, Québec, and New York power markets. External resources available for imports are modeled on an aggregate rather than an individual unit basis. LEI updated the net import flows from neighboring jurisdictions based on hourly profiles created from actual hourly data for 2013-2015. Given major nuclear plant retirements expected in New York (Indian Point), LEI included an adjustment in flows on the Roseton intertie line after 2022. Compared to LEI's October 2015 Report, changes in the import levels on their own are not expected to significantly change the energy market impacts, as the monthly average import levels do not vary more than 2% on most interfaces. Figure 7 below shows the net imports from ISO-NE's neighboring regions used in the Updated Analysis.

[redacted]

[15] For historical congestion analysis, see ISO-NE 2015 Annual Markets Report: <https://www.iso-ne.com/static-assets/documents/2016/05/2015_imm_amr_final_5_25_2016.pdf>. For ISO-NE's 2016 Economic Study results, see: <https://www.iso-ne.com/static-assets/documents/2016/09/a6_2016_economic_study_draft_results_part_2.pdf>. Accessed December 28, 2016.

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Figure 7. Net import/ (net export) with neighboring regions used in LEI modeling (GWh)

Note: Positive numbers represent net exports and negative numbers represent net imports. The net exports to Roseton in 2021 and 2022 (and beyond) are -4,878 GWh and -3,688 GWh. All else being equal, the changes to the Roseton interface results in an immaterial change in annual average wholesale energy prices and therefore do not significantly affect energy market benefits.
Source: ISO-NE historical interchange data, LEI analysis

2.2 Capacity Market Updates

The biggest drivers affecting capacity prices are changes to the FCM demand curves (i.e., the MRI introduces downward pressure in the short term), the Net CONE and reference technology (namely, the ISO-NE's decision to reduce the Net CONE and change the reference technology), as well as known supply changes and retirements (in aggregate, the net supply changes create downward pressure in the short term). These drivers will affect the new generation entry profile and the resulting capacity market benefits expected from NPT.

2.2.1 Demand curve

ISO-NE's latest demand curve improvements (MRI and zonal curves) were approved by FERC in June 2016 and will be implemented starting in February 2017, with FCA #11. In addition, as approved by FERC, the next three FCAs (#11-#13) will feature a transition curve which retains many of the same design elements as the FCA #10 linear downward sloping demand curve, therefore muting the impact of the MRI on FCA prices and outcomes in the near term. Depending on what new resources clear or retire, the MRI curve may replace the transitional demand curve sooner than FCA #14 (see Section 7 for more details on the MRI demand curve and transition curves). Notably, the early phase out of the transition curve is not expected to occur in either the Base Case or the Project Case in the Updated Analysis.

The MRI curve is a convex-shaped demand curve that is based on engineering studies regarding the marginal value of each additional increment of capacity.[16] LEI reviewed various ISO-NE analyses with respect to the MRI and modified its FCA Simulator to include the MRI Curve concept approach.[17]

[16] ISO-NE, ER16-1434-000 Demand Curve Design Improvements. <https://www.iso-ne.com/static-assets/documents/2016/06/er16-1434-000_6-28-16_order_demand_curve_enhancements.pdf>

[17] The demand curves are based on ISO-NE's full-scale reliability planning simulation system (known as Multi-Area Reliability Simulation, or "MARS") to develop the system-wide and zonal demand curves based on market conditions each year, two assumptions were necessary in this analysis. While the set of demand curves produced

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Zonal curves that incorporate local congestion prices for capacity were also approved by FERC for use by ISO-NE, starting with FCA #11. LEI incorporated the implications of price separation due these zonal curves in its FCA Simulator. [redacted] See Section 7 for more information on how LEI modeled the MRI curves.

2.2.2 Net CONE

ISO-NE recently filed with FERC a proposal to change the Net CONE values and switch the reference technology from a combined cycle gas turbine to a combustion turbine (peaker).[21] ISO-NE posits that the Net CONE has come down based on more recent information, and that a combustion turbine is in fact cheaper than a combined cycle power plant. The Net CONE is an important parameter in the FCM, as it directly affects the administrative price cap and also impacts the slope of the demand curve. All else being equal, a lower starting Net CONE value will result in lower capacity market prices. Pursuant to the filing made by ISO-NE with FERC, LEI's Updated Analysis used the ISO-NE recommended Net CONE values as an input to the FCA simulations.[22] The Net CONE value for FCA #11 is based on the combined cycle

for each auction is likely to be quite stable from year to year, they would change slightly to adapt to existing market conditions, which includes differences in market conditions between the Base Case and Project Cases. However, the other components of the MRI curve (including the Net CONE and Penalty Factor) are adjusted each year in line with LEI's estimates. The Penalty Factor is set such that at NICR, the demand curve would clear at Net CONE.

[18] The economic retirements are the same in both the Base Case and Project Case. LEI does not expected any gas-fired entry in the NNE zone under the Base Case or the Project Case. Although the NNE zone would see new wind generation entry, those additions would be limited over time by transmission system constraints. In both the Base Case and Project Case, LEI assumed only 1,000 MW of onshore wind can be brought online.

[19] LEI estimated the Maximum Capacity Limit for the NNE zone using the FCA 11 parameters and extrapolating forward using information from (ISO-NE, Proposed Installed Capacity Requirement Values for the 2020-2021 Forward Capacity Auction (FCA11). <https://www.iso-ne.com/static-assets/documents/2016/09/a2_2020_21_fca11_icr_values_results.pdf>).

[redacted]

[21] ISO-NE FERC Filing ER-17- 795-000. January 13, 2017.

[22] Ibid.

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technology, while FCA #12 uses a combustion turbine. For illustration, the Net CONE values for FCAs #11 and #12 are shown in Figure 8 below. The method used to extrapolate the Net CONE remains the same as in LEI's October 2015 Report, and is described further in Section 6.1.

Figure 8. Comparison of in the Updated Analysis and the LEI Report of October 2015

$/kW-month	LEI Report (2015)	Updated Analysis
FCA 11 Net CONE	$11.09	$11.64
FCA 12 Net CONE	$11.25	$8.04

2.2.3 Imported capacity

LEI used the cleared capacity imports from FCA #10 to determine how much capacity imports would qualify in the next FCA. [redacted]

[redacted]

2.2.4 New entry and retirements

Existing supply in New England was based on the CELT 2016, which was released in May 2016 and provides the recent rated capacity for summer and winter seasons. LEI has also collated extensive data on plant operating parameters (heat rates, variable O&M, forced outage rate, etc.) from a variety of public sources and also from third-party commercial databases. LEI also reviewed the details behind FCA#10 results and the announced winners of the Clean Energy RFP in order to incorporate other resources that have commitments through 2019.[24] [redacted]

[redacted]

[24] Cleared resources in FCA #10 include 485 MW of the Burrillville Energy Center 3 in Rhode Island, 484 MW at Bridgeport Harbor 6 in Connecticut, and 333 MW at Canal 3 in Massachusetts.

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LEI also incorporated known retirements that have been announced since LEI's October 2015 Report was prepared. Such retirements include Pilgrim Nuclear Power Station (June 2019 closure date, announced in October 2015)[25] and Bridgeport Harbor 3 (July 2021 closure date, announced July 2016).[26]

In addition, LEI re-tested the economic performance of all other existing power plants based on updated minimum going-forward fixed cost and determined that in addition to announced retirements, approximately 500 MW of existing generation would retire in the early part of the study period based on project economics under the Base Case. This approximately 500 MW of capacity is included within the 6,000 MW of resources identified by the ISO-NE as being at risk of permanent retirements. These retirements occur in both the Base Case and the Project Case and are therefore independent of Northern Pass. See Section 6.6 for more details on LEI's new entry and retirement methodology.

2.3 Other Updates

2.3.1 Social Cost of Carbon

In order to estimate the incremental social benefit of reduced carbon emissions, LEI used the latest estimates from the Interagency Working Group on Social Cost of Greenhouse Gases ("IWG") on the value of the Social Cost of Carbon ("SCC").[27] As stated by the IWG, the models used to develop the SCC estimates (known as integrated assessment models), "do not include all of the important physical, ecological, and economic impacts of climate change recognized in the climate change literature because of a lack of precise information on the nature of damages

[25] Pilgrim announced its retirement on October 13, 2015 – after LEI completed its modeling for LEI's October 2015 Report. <http://www.entergynewsroom.com/latest-news/entergy-close-pilgrim-nuclear-power-station-massachusetts-no-later-than-june2019/>

[26] See PSEG Power Connecticut LLC PSEG made several commitments in its Community Environmental Benefit Agreement, including, but not limited to, ending commercial operation of Bridgeport Harbor 3 by July 1, 2021 subject to receipt of permits and approvals for Bridgeport Harbor 5. <http://www.ct.gov/csc/lib/csc/pending_petitions/2_petitions_1201through1300/pe1218/filing/pe1218_exhibitg.pdf>.

[27] Interagency Working Group on Social Cost of Greenhouse Gases, US Government. Technical Support Document: - Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis - Under Executive Order 12866. August, 2016. < https://www.epa.gov/sites/production/files/2016-12/documents/sc_co2_tsd_august_2016.pdf >

and because the science incorporated into these models naturally lags behind the most recent research."[28] These limitations suggest that the SCC estimates are likely to be conservative. Both the Fourth and Fifth Assessment Report by the Intergovernmental Panel on Climate Change ("IPCC") also support these findings.[29] Nonetheless, using IWG's SCC estimate is still useful in order to put into context the societal benefit of the CO_2 emission reductions caused by the Project in New England.[30]

Since the October 2015 Report, the SCC has come down slightly as a result of updated data and the results of the Monte Carlo simulations. The IWG did not necessarily expand their scope of environmental and economic impacts in the updated values. The IWG's updates SCC values reduce the estimated societal from CO_2 reductions as a result of Northern Pass, but by less than 5%. Figure 9 below shows the latest SCC values from the IWG.

Figure 9. Comparison of in IWG's estimates of the Social Cost of Carbon ($2007)

$/metric ton, $2007	IWG Report - 2013	IWG Report - 2016
2020	$65.00	$62.00
2025	$70.00	$68.00
2030	$76.00	$73.00

2.3.2 In-service date for NPT and modeling timeframe

LEI changed the in-service date of Northern Pass to January 1, 2020 (previously June 1, 2019) for the ease of modeling based on the latest development schedule provided by Eversource. As a consequence, LEI also deferred the start of capacity sales from the project by one year – Northern Pass's capacity supply obligation ("CSO") is assumed to begin with FCA #12 (previously FCA #11). The capacity market benefits are estimated over a 10-year period from 2021-2030, as opposed to the 2020-2029 in LEI's October 2015 Report. Other characteristics of the Project (such as the projected 7.9 TWh per annum of energy flows and the 1,000 MW CSO level) remained unchanged from the LEI's October 2015 Report.

[28] Ibid.

[29] Ibid.

[30] Notably, these SCC values are applied after the modeling is completed, and therefore do not affect commitment or dispatch in LEI's dispatch simulation model.

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3 Modeling results

LEI's modeling update demonstrates that Northern Pass will deliver significant benefits to ratepayers in the form of lower electricity costs, carbon emissions reduction, and a more efficient system (i.e., production cost savings). Over the first 11 years of operation, wholesale market benefits estimated as a result of NPT average $614 million per year for New England. Although this is lower than the net present value of the benefits estimated in LEI's October 2015 Report (which were $851 million to $866 million), the general magnitude of the updated benefit estimates - in the face of evolving market conditions and changing market rules - is further evidence of the value proposition of the Project for electricity consumers in the region. Over the 11-year modeling horizon, the wholesale energy and capacity market benefits total approximately $4.6 billion on an NPV basis, using a 7% discount rate. Over the modeling period, the state of New Hampshire is estimated to receive a wholesale electricity market benefit averaging approximately $63 million per year (which is comparable to the estimated $81 million to $83 million on average per year reported in LEI's October 2015 Report). Over 11 years, this wholesale electricity market benefit would total approximately $468 million on an NPV basis, using a 7% discount rate. [redacted] below shows the breakdown of the wholesale electricity market benefits between energy and capacity.

[redacted]

3.1 Wholesale energy price outlook and wholesale energy market benefits

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[redacted] The slightly lower energy price reduction is a function of the lower projected natural gas prices modestly lower energy demand projections from ISO-NE, and modified resource mix (including all committed new entrants as of December 2016, announced retirements, and generic new supply).

LEI's October 2015 Report showed that over time, energy market benefits "dissipate" as new and efficient combined cycle gas turbines ("CCGTs") entered the New England market, displacing less efficient price-setting resources in the supply curve and thereby reducing LMPs. With a modification in the preferred technology in the FCM, the technology type of the most economic new entrants changes too (see Section 6.1). LEI therefore modeled peakers as the generic new entrant in both the Base Case and Project Case in the Updated Analysis. Because peakers typically run much less than combined cycle units, they have a lower overall impact on LMPs and NPT's effect on energy market prices lasts longer.[31] Annual average LMPs are consistently lower in the Project Case as compared to the Base Case in the Updated Analysis over the whole modeling timeframe, as seen in Figure 11 below. Indeed, we expect the estimated energy market benefits to last for some time past the modeled timeframe.

[redacted]

[redacted]

While the reference technology increases the longevity of the energy market benefits, lower demand expectations in CELT 2016 compared to CELT 2015 place downward pressure on the magnitude of the wholesale energy market benefits in the Updated Analysis.

In addition to calculating the wholesale energy market benefits for New England as a whole, LEI also estimated the energy market benefits for wholesale load in New Hampshire. LEI isolated the wholesale load for New Hampshire in its model and multiplied that load by the projected demand-weighted zonal LMP differences for the New Hampshire zone. On average, LEI expects New Hampshire wholesale load to benefit from the reduced LMPs by approximately $8.6 million per year on average. Using a 7% discount rate, the NPV is approximately $64 million in savings over the modeled timeframe (in 2020 dollars).

3.2 FCA outlook and wholesale capacity market benefits

[redacted]

The lower wholesale capacity market benefits can be attributed to the shape of the demand curve has changed, the lower peak demand forecasts from ISO-NE, and the lower net CONE values. Nevertheless, the beneficial effect of NPT on capacity prices remains – as the new MRI curves continue to essentially institutionalize the concept of lower prices for increased supply.

The chart in [redacted] shows the level of procured capacity under the updated Base Case and Project Case. The graph illustrates how Northern Pass creates more supply in the Project Case (starting with FCA #12) relative to the Base Case. The modeling captures the fact that the full 1,000 MW of additional supply from NPT's 1,000 MW CSO is muted by delists (from New York imports and also from a static delist for one year from an existing generator). Nevertheless, the net additional supply from NPT creates wholesale capacity market benefits that last for six years – until the point when generic combustion turbines would otherwise have come online but for NPT (i.e. until there is generic entry in the Base Case). These generic power plant additions are delayed in the Project Case because they are not economic and as a result, the total level of cleared capacity equilibrates between the updated Base Case and the updated Project Case by FCA #18. As with the modeling in LEI's October 2015 Report, there is a small variation in capacity prices that continues past FCA #18, due to the expected difference in Net CONE values (for a generic peaker) over time under the Base Case and Project Case (particularly

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because of NPT's effect on peak period energy market prices).[32] As a result, we see small differences in the projected capacity market prices for FCA #18-#21.

[redacted]

Taking together the introduction of the MRI demand curve, the revised starting Net CONE values, reduced peak demand, and the supply and demand projections, the wholesale capacity market benefits over the 10-year modeling period decreased to $579 million on average per year, down from the range of $843 million to $848 million in LEI's October 2015 Report. [redacted] below shows the projected wholesale capacity prices under the Base Case and Project Case, which underpins the wholesale capacity market benefits for ISO-NE as a whole. In order to isolate the wholesale capacity market benefits for New Hampshire, LEI allocated a portion of the total wholesale capacity market benefits for New England to each state by using each state's coincident peak load share in CELT 2016. On average, LEI expects New Hampshire wholesale load to benefit by approximately $60 million per year on average. Using a 7% discount rate, the NPV of these projected capacity market savings over the modeling period totals $404 million (in 2020 dollars).

[32] See Section 2.2.2 of this Updated Analysis for a description of how the Net CONE is derived (LEI starts with ISO-NE's latest projected starting values for Net CONE, and thereafter applies an escalation consistent with ISO-NE's Market Rule 1). This is the same methodology used in LEI's October 2015 Report.

[redacted]

3.3 Production cost savings

Under the Updated Analysis, as a result of NPT's operation and the projected energy flows, the average production cost savings for ISO-NE from avoided short run marginal costs of production are forecast to be $389 million per year. As was the case with LEI's October 2015 Report, this production cost savings estimate assumes that the physical short run marginal costs (i.e., fuel costs) of the energy flowing on Northern Pass is zero (which is generally consistent with the physical characteristics of hydroelectric-based energy).

Production cost savings arise because energy flowing on Northern Pass displaces other fossil fuel fired generation (and as such, production cost savings are primarily comprised of avoided fuel costs). As shown in Figure 2, the natural gas prices in the Updated Analysis fall in between the two gas scenarios studied in LEI's October 2015 Report. Intuitively, production cost savings should fall somewhere between these two levels.

As discussed previously, the energy flows on Northern Pass remain constant over the modeling timeframe, while the short run marginal costs of the generating resources that are being displaced by energy flows on Northern Pass increase moderately over time due to rising fuel prices and carbon allowance prices, in nominal dollar terms. As a result, LEI observed a moderate increase in the production cost savings over time. Using a 7% discount rate, the 11-year NPV sum of the annual production cost savings is approximately $2.9 billion (in 2020 dollars) in the Updated Analysis, compared to the range of $2.4 billion to $3.1 billion (in 2019 dollars) in LEI's October 2015 Report.

[redacted] below shows the derivation of the annual production cost savings over the modeling horizon for the NECA.

[redacted]

3.4 Environmental benefits

3.4.1 CO_2 reductions as a result of Northern Pass

The results of LEI's modeling show that Northern Pass reduces CO_2 emissions by approximately 3.2 million metric tons in New England.[33] Similar to production cost savings, the CO_2 emissions reduction is fairly constant because of the assumed level of energy flows on Northern Pass and the similarity in the emissions footprint of the generating resources that are being displaced by the energy flows on NPT.

[redacted]

3.4.2 Incremental social benefits of carbon emissions reductions

LEI also estimated the incremental value to society of the avoided CO_2 emissions, using an updated SCC forecast from the IWG. Based on the latest published SCC values, LEI estimated that Northern Pass will create approximately $189 million in annual, incremental social benefits from CO_2 reductions for New England, based on the IWG's SCC projections under the 2.5% average discount rate scenario. The NPV of these incremental social benefits over the first 11

[33] According to the calculator available on the Environment Protection Agency website, this is equivalent to removing approximately 675,000 passenger vehicles per year. *See*. "Calculations and References." <https://www.epa.gov/energy/ghg-equivalencies-calculator-calculations-and-references#vehicles>. Accessed December 28, 2016.

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years of operation of NPT is estimated to be approximately $1.3 billion (in 2020 dollar terms, using a 7% discount rate in the NPV estimate).

For information purposes, LEI also calculated the incremental social benefits of the avoided CO_2 emissions in New England under the IWG's more conservative scenarios of SCC (namely the 3% and 5% discount rate scenarios).[34] Even under these very conservative estimates of future SCC, the incremental social value to New England over the first eleven years of NPT's operation ranges from $25 million a year (or $187 million NPV) to $123 million a year (or $914 million NPV). A comparison of these results from the Updated Analysis relative to LEI's October 2015 Report can be found in [redacted]

[redacted]

It is important to note that these incremental social benefits include a deduction for the assumed CO_2 emitted by the large hydroelectric plants in Québec. This deduction is made in order to consider the CO_2 emissions at the "source" of the energy flows on Northern Pass. In LEI's October 2015 Report, LEI used the emissions rate from a study that assessed the carbon footprint associated with the creation of a boreal hydroelectric reservoir (Eastmain-1 in northern Québec, Canada).[35] The emissions rate was found to be 136 lbs/MWh, which LEI believes is reasonable and therefore continued to use it.[36] This results in approximately 490,000 metric tons of CO_2 to be netted out of the 3.2 million metric tons of avoided CO_2 given the 7,958 GWh of energy imported annually from Quebec.

[34] For reference, the 2025 values for the 5%, 3%, and 2.5% average discount rates are $14, $46, and $68 per metric ton in 2007 dollars. For 2030, these values are $16, $50, and $73 per metric ton respectively.

[35] Teodoru, C. R., et al. (2012), The net carbon footprint of a newly created boreal hydroelectric reservoir, Global Biogeochem. Cycles, 26, GB2016.

[36] A report produced by the International Reference Centre for the Life Cycle of Products, Processes and Services ("CIRAIG") suggests that the levelized average emissions of the electricity generated, transmitted and distributed by Hydro-Québec is 20.72 g CO2 eq/kWh (167 lbs/MWh). However, this includes electricity purchases made by Hydro-Québec from private producers or neighboring markets. Netting out electricity purchases, this emissions rate would fall to 13.1 g CO2 eq/kWh (105 lbs/MWh). To remain conservative, LEI continued to utilize the 136 lbs/MWh emissions rate estimate based on the Teodoru (2012) study.

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4 Conclusions

Key market drivers and wholesale market rules will evolve and change over time. It is unrealistic to assume that any forecast will perfectly predict the precise market impacts of Northern Pass over the next 10-15 years. However, this Updated Analysis shows that even in the face of emerging shifts in market conditions due to changes in underlying drivers or as a result of evolving market rules, Northern Pass will create substantial wholesale market benefits for consumers, in the form of lower electricity costs. As can be expected, some drivers will move in such a way as to increase the monetary value of the wholesale electricity market benefits (such as higher natural gas prices) while others will reduce the value of wholesale electricity market benefits (such as lower demand).

The overall methodology and modeling approach taken to calculate the wholesale electricity market impacts and associated benefits in the Updated Analysis is unchanged from LEI's previous analysis in October 2015. However, LEI did account for the latest capacity market rules and major developments in key drivers (such as fuel prices, supply, and demand). In summary, LEI's modeling update demonstrates that the expected benefits to ratepayers in the form of lower electricity costs from Northern Pass are robust and substantial.

In addition to the projected wholesale market benefits, Northern Pass will create production cost savings of$389 million on average per year for New England. In line with the energy and gas price trends, this falls between the expected production cost savings of the two gas scenarios presented in LEI's October 2015 Report, which were $330 million and $425 million on average per year.

The local economic benefits were not updated in this analysis as the expected local spending during construction has not changed. The local economic benefits associated with the operations phase of NPT are primarily driven by the wholesale electricity market benefits, which drive retail cost savings. Although the wholesale electricity market benefits are smaller in the Updated Analysis as compared to LEI's October 2015 Report, they are nonetheless substantial. Therefore the local economic benefits once NPT begins operations would continue to be material.

The environmental benefits of the project are largely unchanged, with a CO_2 reduction of approximately 3.2 million metric tons in New England as a result of Northern Pass. While there may be a debate about the precise value attributed to the social cost of carbon in each future year, under all the discount rate scenarios that the IWG published, the value of the incremental social benefits of reducing CO_2 emissions in New England is significant. In the coming years, as New England states seek to retain their leadership in reducing GHG emissions in the electricity sector, projects such as Northern Pass will be increasingly important in achieving these goals.

In conclusion, LEI's Updated Analysis, like its October 2015 analysis, indicates that Northern Pass would produce significant wholesale market benefits for New England ratepayers and result in a regional power system that is emitting less CO_2, supporting many states' GHG emissions goals. This Updated Analysis also demonstrates that the overarching findings regarding the environmental and economic benefits of NPT included in LEI's October 2015 Report are still generally valid for the purposes of the SEC proceeding.

5 Appendix A: Recap of the LCOP model and forecast of gas prices

As discussed in LEI's October 2015 Report, two methods were used to develop delivered gas prices in New England. The first method used LEI's Levelized Cost of Pipeline Model ("LCOP")[37], which relies on cost of new pipelines and identification of the tipping point when forward (forecast) trends in the transportation basis consistently (without weather-driven events) exceed the cost of new pipeline capacity. The LCOP model relies on publicly announced pipeline construction costs across the US.[38] The LCOP model also relies on a Henry Hub outlook. In LEI's October 2015 Report, the LCOP-based gas forecast relied on natural gas price trends in EIA's Reference Case from AEO 2015. Since then, EIA has revised its Henry Hub outlook as new information around production, demand, and transportation became available.[39]

The second method used in LEI's October 2015 Report to forecast delivered gas prices in New England used the output of the GPCM model, developed by RBAC. The GPCM model is a transportation-based model of the North American gas market.

In LEI's Updated Analysis, consistent with the Motion to Compel from the SEC, LEI performed an update on its LCOP-based forecast, as that is the only forecast that relies on the EIA's AEO publications. The AEO 2016 Reference case includes updated assumptions about production, demand, and ongoing innovation in upstream technologies, which in aggregate result in lower commodity prices in the long term. As shown in Figure 2 on page 10, for New England, forecasted natural gas prices rise more quickly in the beginning of the forecast before leveling out at a slower growth rate towards the end of the forecast timeframe. Figure 17 below shows the Henry Hub Outlook in the AEO 2016 Outlook. LEI relied on the price trends of the Reference Case for developing the longer term Algonquin Citygate forecast for this Updated Analysis.

[37] The Levelized Cost of Pipeline ("LCOP") model covers 28 trading hubs in North America and evaluates the gas basis between any two hubs relative to the LCOP. Costs are assumed to increase in nominal terms over time (2%per year) to reflect inflation. We examined the differential in forwards for Henry Hub ("HH") prices and the Algonquin Citygate hub. If the average of the 3-year price difference between the two hubs is higher than the levelized cost of building a pipeline between the two hubs, a pipeline will be built at the beginning of the fourth year. The overall basis comes down to the LCOP cost, multiplied by the miles between the constrained hubs. The LCOP model however, does not specify the size (throughput) of the pipeline expansions. The model also assumes that additional gas pipeline capacity is added only when economic and only at the incremental level needed to converge to market basis with the costs of expansion. **Error! Reference source not found.** below shows the Algonquin Citygate prices produced by the LCOP model.

[38] Using pipeline projects filed with FERC with an expected in service date between 2016 and 2018, LEI estimated the LCOP to begin at approximately $0.004 MMBtu/year/mile. That figure was then escalated with inflation during the forecast timeframe.

[39] For EIA's latest Annual Energy Outlook 2016, see: < http://www.eia.gov/outlooks/aeo/>.

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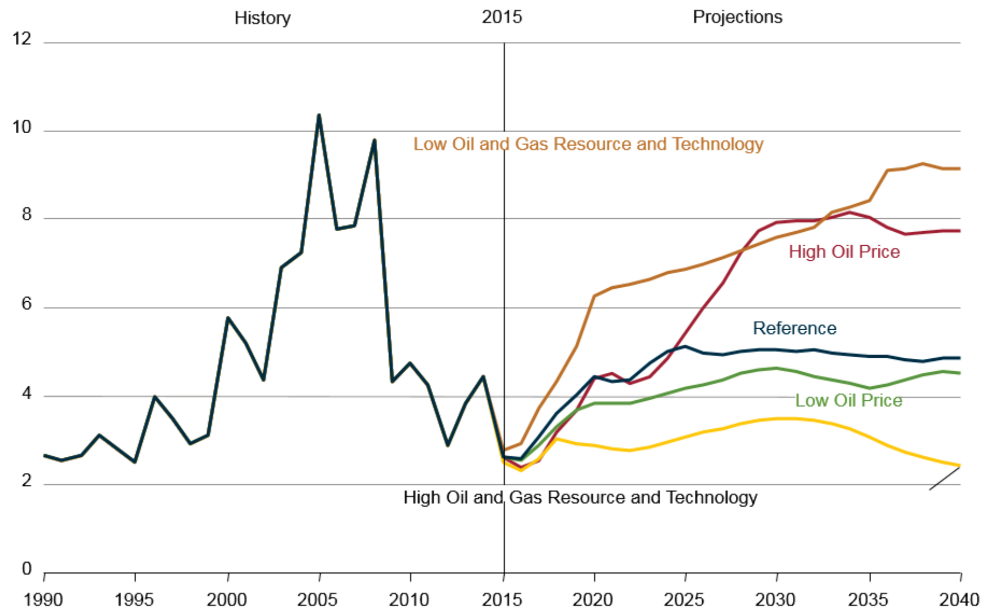
Figure 17. Annual average henry hub natural gas spot market prices (1990-2040), in 2015 $/MMBtu (real dollar terms)



Source: EIA Annual Energy Outlook 2016, Figure MT-42.
<http://www.eia.gov/outlooks/aeo/MT_naturalgas.cfm#price_product>. Accessed December 28, 2016.

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6 Appendix B: Detailed assumptions and inputs for capacity market modeling, new entry and retirements

6.1 Choosing a reference technology and projecting Net CONE

As discussed earlier, LEI used the updated Net CONE values and reference technology from recent ISO-NE filings with FERC. ISO-NE has proposed to use peaking technology[40] as the reference technology for future FCAs, starting with FCA #12. This decision was taken based on analysis of the most cost-effective and economically viable technology being actively developed in New England.[41] In modeling new entry in the Updated Analysis, LEI used the same technical assumptions used in the study underpinning ISO-NE's decision (including heat rates, dual fuel capability, and approximate unit size), as summarized in Figure 18 below.

Figure 18. Net CONE Summary for Candidate Reference Technologies (2021$)

Reference Technology	Installed Capacity	Installed Cost (2021$)	Installed Cost (2021$)	ATWACC	Fixed O&M	Gross CONE	Revenue Offets	Net CONE
	(MW)	*(000$)*	*($/kW)*	*(%)*	*($/kW-mo)*	*($/kW-mo)*	*($/kW-mo)*	*($/kW-mo)*
1x1 7HA.02 (CC)	533	$ 598,958	$ 1,124	8.1	$ 5.01	$ 15.62	$ 5.62	$ 10.00
1x0 7HA.02 (CT)	338	$ 304,179	$ 900	8.1	$ 3.21	$ 11.35	$ 3.31	$ 8.04
2x0 LM6000 PF+ (Aero)	94	$ 198,363	$ 2,110	8.1	$ 6.96	$ 25.98	$ 3.63	$ 22.35
1x0 LMS100PA (Advanced Aer	103	$ 174,644	$ 1,696	8.1	$ 5.75	$ 21.03	$ 3.67	$ 17.36

Source: ISO-NE FERC Filing ER-17- 795-000. January 13, 2017.

The key factors contributing to ISO-NE's proposed (lower) Net CONE values include: lower capital costs (gross CONE) for the simple cycle turbine, as well as a (higher) E&AS offset, which is composed of primarily ancillary services revenues and Pay-for-Performance ("PFP") revenues. The E&AS offset is deducted from the gross CONE to yield the net CONE. ISO-NE has filed a request with FERC to use the Net Cone value of $8.04 for FCA #12. While FERC has not yet approved these updates at the time of this Updated Analysis, LEI believes that FERC will approve of the ISO-NE's proposal as other RTOs also use peaking technology as the reference technology in their organized capacity markets. [redacted] below shows the Net CONE values used in LEI's Updated Analysis.

[40] Simple cycle gas turbines and combined cycle turbines were both assumed to use the GE 7HA 0.2 Frame technology, but with different configurations for steam turbines and duct firing for the combined cycle gas turbines.

[41] ISO-NE FERC Filing ER-17- 795-000. January 13, 2017.

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[redacted]

6.2 New York Import Capacity

New England is interconnected with Maritimes, New York, and Quebec, and resources in these regions have in the past qualified and sold capacity supply obligations as an import resource in the FCA. Among these neighboring regions, New York is the only other region with an organized capacity market. In theory, this presents an opportunity cost for resources located in New York when selling their capacity into New England.

The New England system is affected by market developments in neighboring markets. This includes recent and significant changes to New York's resource outlook. The 2,050 MW Indian Point nuclear plant recently announced that it has reached a deal with the Governor of New York to shut down the plant: the first unit may retire as early as April 2020, with the second unit retiring one year later (although the agreement allows for some deferment of the retirements, if system conditions necessitate delay due to reliability concerns).[42] At the same time, certain new generation projects have recently received financial commitments from investors to get built.[43] LEI projects that these retirements and subsequent new entry will have impacts on New York's wholesale energy and capacity market. Based on the relative projected prices of capacity in New York and in New England, LEI expects some New York import resources to rationally choose to exit the ISO-NE FCM (in favor of sales to the NYISO capacity market) when ISO-NE FCA prices fall due to NPT's sale of capacity. LEI also projects that once capacity prices rise back up in New England and surpass capacity prices in the relevant locality in NYISO's capacity market, those same capacity imports will come back to New England.

[redacted]

[42] Entergy Newsroom. *Entergy, NY Officials Agree on Indian Point Closure in 2020-2021*. Accessed January 10, 2017. < http://www.entergynewsroom.com/latest-news/entergy-ny-officials-agree-indian-point-closure-2020-2021/>

[43] Cricket Valley Energy. *Cricket Valley Energy Center, LLC Closes Financing of $1.584 Billion Energy Center in Dover, New York*. Accessed January 27, 2017. <http://www.cricketvalley.com/news/17-01-24/Cricket_Valley_Energy_Center_LLC_Closes_Financing_of_1_584_Billion_Energy_Center_in_Dover_New_York.aspx>

[44] LEI used an update of its general multi-client NYISO capacity price outlook to determine the reasonableness of New York delist levels.

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[redacted]

6.3 Other Delists

In ISO-NE, existing resources may choose to submit a permanent de-list, a static delist or a dynamic delist. A static delist bid provides an option to remove capacity from the capacity market at or above $5.50/kW-month (known as the dynamic delist threshold or "DDBT") for a single capacity commitment period only. This requires a cost justification that is reviewed by the IMM.[45] Once approved, a static delist cannot be changed. A dynamic delist bid does not need to be reviewed by the IMM, and may be submitted by the resource at any time during the FCA.[46]

Figure 22 below shows how the static delists have evolved over time. As the ISO-NE has raised the DDBT and market conditions evolved, the amount of static delist requests has materially declined. Specifically, for FCAs #8 and #9, there were many more static delists as the DDBTs were set very low ($1.00/kW-month and $3.94/kW-month, respectively). The red bars also indicate the static delists were withdrawn prior to the auction (static delist bids are submitted for a resource approximately eight months before the FCA).[47]

Another key observation from the figure below is that there are very few static delists being requested for FCA #10. This is not surprising, given the DDBT was raised to $5.5/kW-month for FCA#10. Indeed, roughly 97% of resources that bid into the New England FCA did not submit a static delist bid for FCA #10. Although resources that have not asked for a delist above

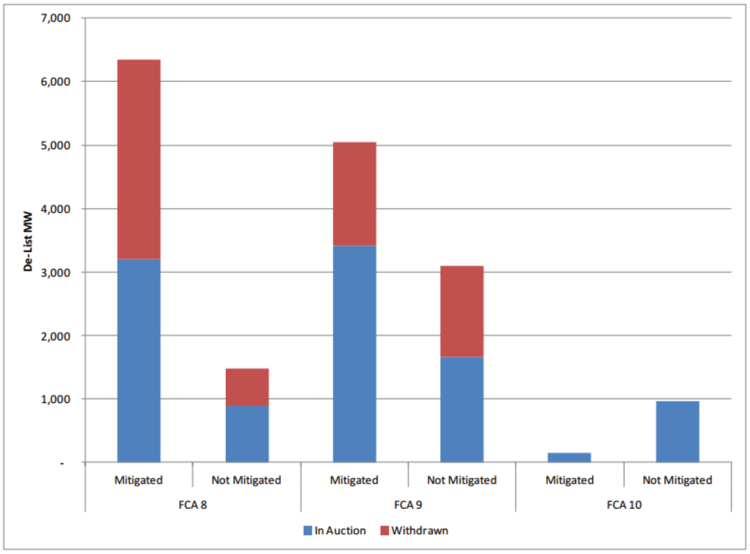
[45] See Market Rule 1. Section III.13.1.2.3.1.1.

[46] Ibid.

[47] For FCAs #8, #9 and #10, the IMM applied mitigation to approximately 63% of the static de-list bids it reviewed. Participants with generation resources subsequently withdrew 54% of the static delist-bids that were mitigated. See ISO New England's Internal Market Monitor, 2015 Annual Markets Report, pg. 188.

the DDBT still have the opportunity to dynamically delist, we would not expect many dynamic delists so long as resources are able to meet their performance obligations (and associated costs). Rational economic behavior would suggest that a resource that is not considering retirement would prefer to not delist the FCA so long as they are able to cover the risks of capacity performance – since the capacity market provides a revenue stream to defray fixed costs of operation that would not otherwise be available. ISO-NE has estimated that the average cost of performance risk is in the range of $1.8/kW-month for the most marginal resources in the capacity market.[48]

Figure 21. Static Delist Bids in FCAs #8, #9, and #10



Source: ISO New England's Internal Market Monitor, 2015 Annual Markets Report, pg. 189.
Note: The DDT price was $1.00, $3.94, and $5.50/kW-month for FCAs 8, 9, and 10 respectively

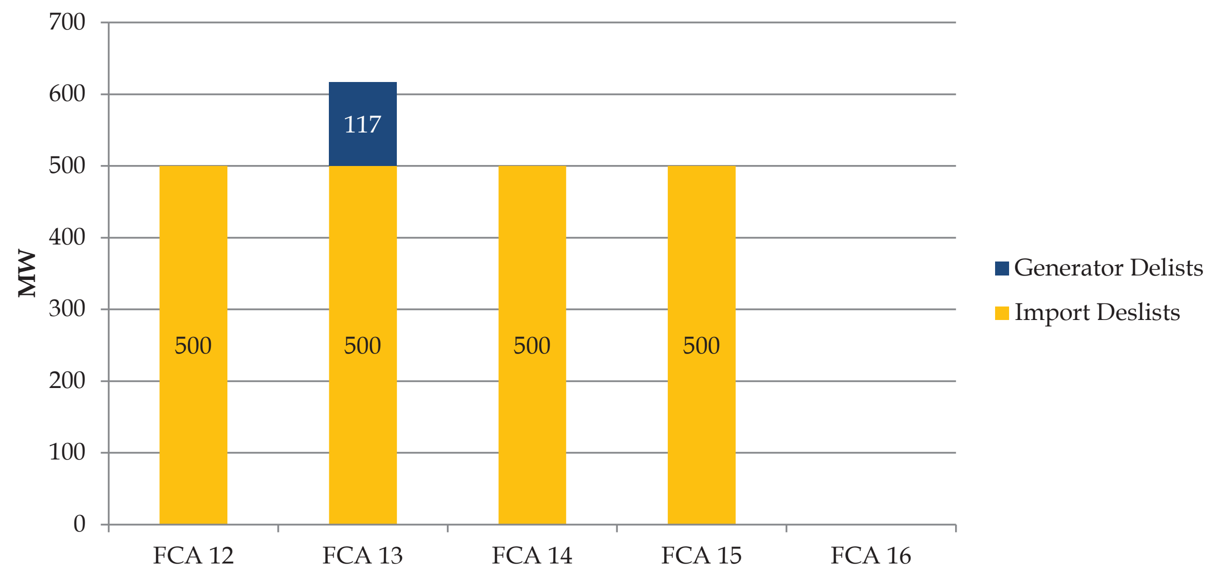
LEI has reflected the nuances of static and dynamic de-lists in its simulation modeling of future FCAs. Specifically, LEI assumed that those resources with estimated going forward fixed costs that exceed the DDBT would be candidates for static delists and would in fact de-list if prices decline in the FCA below their minimum going forward fixed costs. And if such a resource would not see an opportunity to clear in future FCAs, they would eventually retire, pursuant to our economic retirement trigger of three unprofitable years of operation. On the other hand, resources with minimum going forward fixed costs below the DDBT would be dynamic delist candidates and would be willing to accept a lower capacity price so long as clearing prices do not go below their "costs" (risk premium) for capacity performance. The economic intuition behind this strategy is that resources would typically prefer to get some capacity revenues

[48] McDonald/Laurita Testimony

rather no capacity revenues to defray their fixed operating costs, so long as they are not in a position to be considering permanent delist/retirement.

In the Updated Analysis, based on LEI's estimate of minimum going forward fixed costs for existing generators, there are several oil-fired steam generators at the top of the FCA supply curve, in between $5.50/kW-month and $6.00/kW-month.[49] These are the resources that we see reacting (delisting) due to lower capacity auction clearing prices. However, under the updated Base Case, FCA prices do not fall to the levels that would trigger delists. And in the updated Project Case, there is only one year (FCA #13) where a de-list is triggered of a 120 MW unit. And in the following year's FCA (FCA #14), that unit is projected to clear the FCA, as FCA prices rise and exceed the unit's estimated minimum going forward fixed costs. Figure 23 below shows the combined capacity of the generator delist and New York import capacity delists (from the Base Case level of 1,045 MW) that LEI projected for FCA #12 through FCA #16 under the updated Project Case.

Figure 22. Delists modeled in FCAs #12-#16 under the updated Project Case



6.4 Renewable New Entry

For solar PV (both metered and behind the meter), LEI adopted ISO-NE's 2016 solar PV forecast.[50] This includes over 1,450 MW of solar PV resources from 2020-2030, roughly 70% of

[49] This section of the supply curve is relatively flat as a result of the marginal gas/oil steam units earning no energy market revenues. In LEI's October 2015 Report, this flat portion was estimated to be $5.5/kW-month, requiring only 300 MW of import delists in FCA #11.

[50] ISO-NE. Final 2016 PV Forecast. Distributed Generation Forecast Working Group. April 15, 2016.

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which is behind the meter. Consistent with the ISO-NE forecast, resources built beyond 2019 are not assumed to receive a CSO, with most of the growth occurring behind the meter.

[redacted] Figure 23 shows the nameplate capacity of solar PV and wind resources added in the modeling horizon, as well as the assumed CSO. Resources selected in the Clean Energy RFP are embedded within the solar PV and onshore wind forecast.

Figure 23. Generic renewable resource additions from 2020-2030 under the Base Case and Project Case

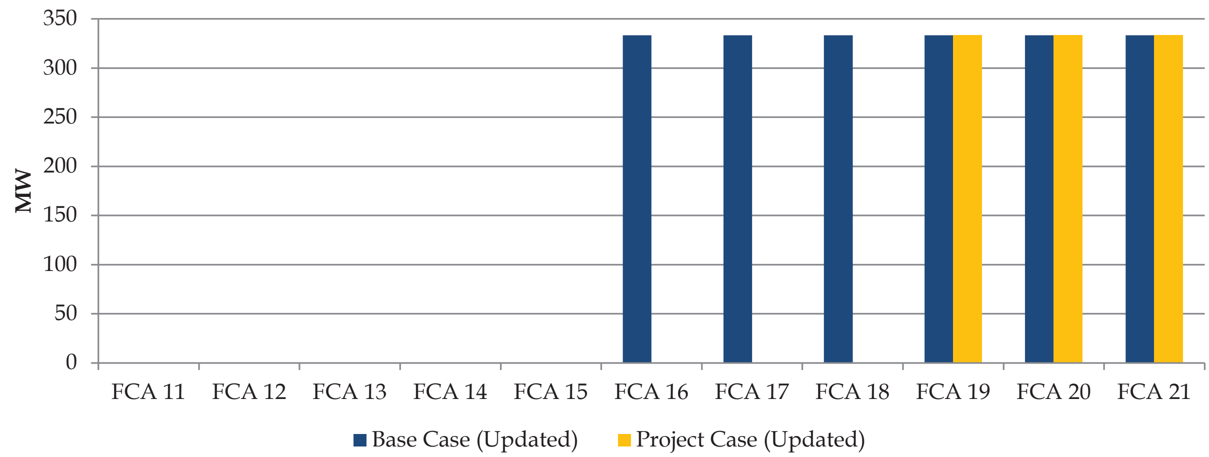
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Nameplate MW												
Solar PV	177	133	128	118	118	118	118	118	118	118	118	1,383
Onshore Wind	185	185	185	185	185	0	0	0	0	0	0	925
CSO, MW												
Solar PV	0	0	0	0	0	0	0	0	0	0	0	0
Onshore Wind	28	28	28	28	28	0	0	0	0	0	0	139

6.5 Thermal New Entry

Over the long term, LEI assumed that generators make "just-in-time" capacity investment decisions that were timed to peak load growth and the "needs" demonstrated in the projected supply-demand balance of ISO-NE's FCM. Given the load growth and retirements, the modeling revealed a "need" for 2,000 MW of new thermal entry in the updated Base Case and 1,000 MW of thermal entry in the updated Project Case by 2030.[51] LEI tested both CCGTs and peakers in the Updated Analysis, but due to the modeled operations of each technology and the fact that Net CONE was set against a peaking technology, the most economic new entrant was a peaker. The generic peaking units were sized at 333 MW each, which is just below the nameplate capacity of a GE 7HA 0.2 Frame unit (337 MW) and is consistent with the levels cleared by Canal 3 in FCA #10, which used that type of technology. As seen in the figure below, the first generic peaker enters the market in FCA #16 under the Base Case. The introduction of the NPT under the Project Case defers the entry of a generic new peakers until FCA #19.

[51] The cumulative level of generic entry in the Updated Analysis is consistent with LEI's October 2015 Report (which included 2,200 MW of generic combined cycle units in the Base Case and 1,200 MW of generic combined cycle units in the Project Case). As a result of lower peak demand forecast (CELT 2016), and due to size differentials between the combined cycle units in previous analysis and peaking technology modeled in the Updated Analysis, there are fewer resources "needed" in the Updated Analysis.

Figure 24. Quantity and timing of generic gas-fired entry in the Updated Analysis



6.6 Retirements

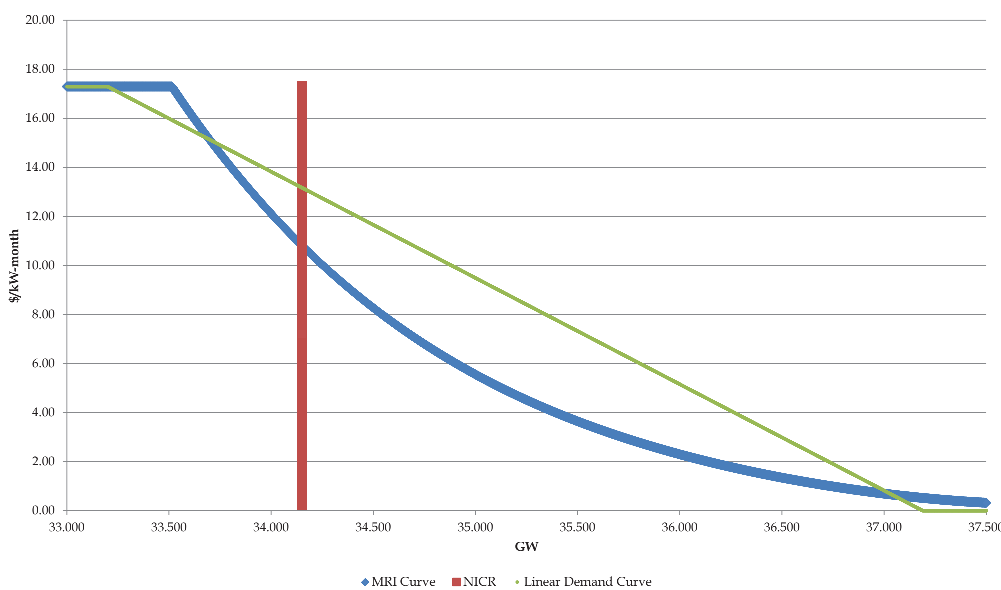
LEI incorporated all announced retirements into the Updated Analysis as of January 2017, which includes Pilgrim Nuclear Power Station (retirement date of June 2019) and Bridgeport Harbor 3 (retirement date of July 2021). In the summer of 2016, LEI also updated its minimum going-forward fixed costs for different resource types based on publicly available sources, as well as LEI's original research. Generators in the region found to have higher minimum going-forward costs[52] than what can be expected to be earned from the wholesale power market were assumed to retire in the Updated Analysis.

7 Appendix C: LEI's approach for capturing the convex demand curves

On April 15, 2016, ISO-NE filed its Demand Curve design improvements with FERC. These capacity market reforms aimed to address the shortcomings of the linear downward sloping demand curve that was used for FCA #9 and #10 (the linear demand curve formulation was also relied upon by LEI in its capacity market analysis for the October 2015 Report). The new set of demand curves (MRIs) is based on the principles of maximizing reliability, sustainability, and cost-effectiveness. In doing so, the demand curve took on a curved or convex shape so as to reflect the nonlinear relationship between quantity and ISO-NE's willingness to pay for the marginal improvement in reliability associated with adding new capacity.[53]

The MRI curve has a steeper slope left of Net ICR value ("NICR") because the marginal impact of adding one additional resource is high. Once supply crosses to the right over the NICR level on the MRI, the curve has a flatter slope to signify that the marginal impact of adding one additional resource is lower. The linear demand curve assumes implicitly that each additional MW has the same marginal reliability impact. Figure 25 shows an illustrative example of the MRI curve against the downward sloping demand curve for FCA #10 based on ISO-NE's indicative demand curve example.[54]

Figure 25. Illustrative example of linear demand curve and MRI curve



[53] For more details, see ISO-NE's December 7, 2015 technical memorandum to the NEPOOL Markets Committee on the FCM Zonal Demand Curve Methodology.

[54] ISO-NE Indicative Demand Curve Values for FCA 10 Zones. <https://www.iso-ne.com/static-assets/documents/2016/01/a02_iso_indicative_demand_curve_values_fca10_zones_01_06_16.xlsx >

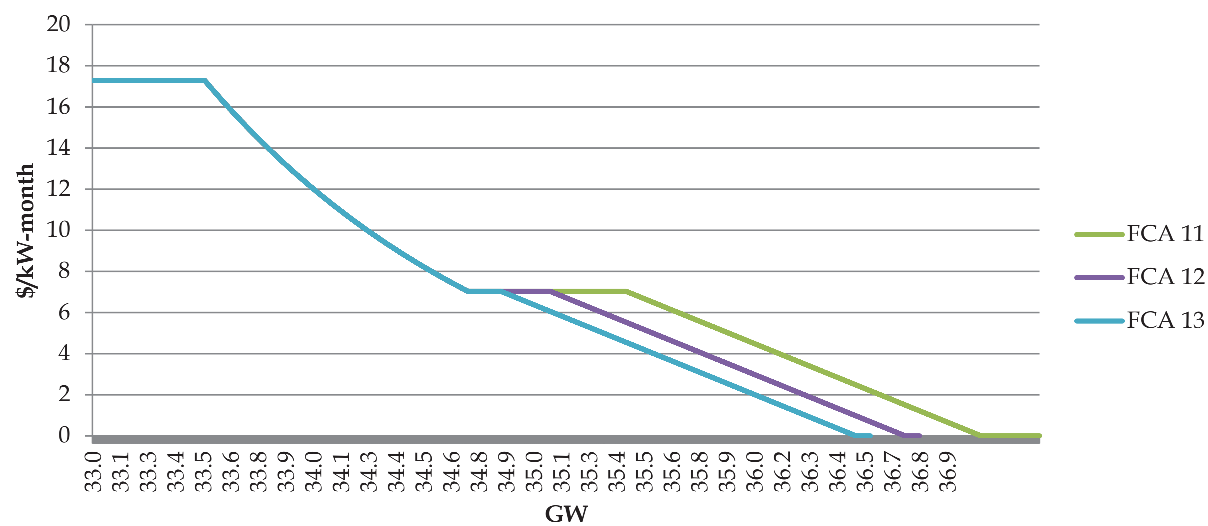
To obtain the capacity clearing price in the FCA, the following equation must be applied against the MRI curve:

$$Price_{System}(Quantity_{System}) = -Penalty\ Factor\ \times MRI$$

PF, refers to the Penalty Factor, which LEI assumes is set such that the clearing price capacity at NICR will equal Net CONE (where the Loss-of-Load Expectation is 0.1). Therefore, at any given level of Q (i.e. the amount of resources in the FCM), the price can be determined by the MRI at that particular quantity and the PF. Please refer to Section 6.1 for details on how LEI forecast the Net CONE.

For FCA #11 through FCA #13, a set of transition curves were also approved by FERC in order to ease market participants into the new MRI concept – the transition curves gradually shift from the linear demand curve to the MRI curve. In other words, these transition curves are a hybrid of the existing linear demand curve design and the new MRI curve. The transition period may end earlier than FCA #13 (and the new MRI-based system curve would then begin in the next auction) if load growth (specifically, NICR) increases above certain specified levels. These NICR threshold levels are the sum of: 34,151 MW, and: (i) 722 MW (for FCA #11); (b) 375 MW (for FCA #12), or; (c) 150 MW (for FCA #13). Figure 26 below shows the transition curves for FCA #11 through FCA #13. In LEI's analysis, based on ISO-NE's CELT 2016 forecast of peak demand, it is not expected that the transition period would end before FCA #13.

Figure 26. Transition Curves, FCA #11-#13



In practice, the MRI would shift over time as new resources enter and exit the system and demand grows. ISO-NE's engineering-based approach to build up the MRI produces a set of coefficients that are used to plot the convex demand curve for each capacity zone. While the shape of the zonal convex demand curves produced for each auction may change slightly each

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year, ISO-NE has noted publicly that they expect these curves to be quite stable from year to year.[55] LEI therefore used the latest available coefficients from ISO-NE[56] to recreate the MRI demand curve, and then shifted the curves to the right each year (by the growth in NICR), and scaled the curves using expected Net CONE values.

New generic thermal capacity resources were developed in SENE given: i) what has been observed in recent capacity auctions in terms of which capacity zones peakers are clearing in, ii) the locational distribution of resources in the interconnection queue which are mostly in Rest of Pool and SENE, and iii) the practicalities of building new resources where pipeline and transmission infrastructure are the most developed. This new entry leads to an equilibrium condition where the SENE clearing price aligns with the Rest of System clearing price in both the Base Case and Project Case.

In addition, as a result of approximately 500 MW of economically driven retirements in the Base Case, LEI projected that a separate (lower) clearing price for the NNE zone would not be triggered. In order to model the NNE zone, LEI evaluated the existing Maximum Capacity Limit ("MCL") calculations by ISO-NE extrapolated this calculation for future FCAs consistent with the modeled supply conditions in the NNE zone.[57] This result as observed under the Base Case as well as the Project Case (even with 1,000 MW of capacity from NPT).[58]

[55] See Christopher Geissler and Matthew White Testimony on behalf of ISO-NE. Docket ER16-1434-000

[56] ISO Indicative Demand Curve Values for FCA Zones, March 2, 2016.

[57] LEI estimated the expected MCL for the NNE capacity zone using the FCA 11 parameters and extrapolating forward (using information from ISO-NE, Proposed Installed Capacity Requirement Values for the 2020-2021 Forward Capacity Auction (FCA11). <https://www.iso-ne.com/static-assets/documents/2016/09/a2_2020_21_fca11_icr_values_results.pdf>).

[58] Such an outcome is also a reasonable assumption given that neither FCA #9, FCA #10, nor FCA #11 resulted in the formation of a separated export-constrained capacity zone price in New England.